

APPENDIX C-1

IMP Rule section 195.450-(Appendix C)

This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule in §§ 195.450 and 195.452. Guidance is provided on:

- (1) Information an operator may use to identify a high consequence area and factors an operator can use to consider the potential impacts of a release on an area;
- (2) Risk factors an operator can use to determine an integrity assessment schedule;
- (3) Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a pipeline segment falls into a high, medium or low risk category;
- (4) Types of internal inspection tools an operator could use to find pipeline anomalies;
- (5) Measures an operator could use to measure an integrity management program's performance; and
- (6) Types of records an operator will have to maintain.
- (7) Types of conditions that an integrity assessment may identify that an operator should include in its required schedule for evaluation and remediation.

I. Identifying a high consequence area and factors for considering a pipeline segment's potential impact on a high consequence area.

A. The rule defines a High Consequence Area as a high population area, an other populated area, an unusually sensitive area, or a commercially navigable waterway. The Office of Pipeline Safety (OPS) will map these areas on the National Pipeline Mapping System (NPMS). An operator, member of the public, or other government agency may view and download the data from the NPMS home page <http://www.npms.rspa.dot.gov>. OPS will maintain the NPMS and update it periodically. However, it is an operator's responsibility to ensure that it has identified all high consequence areas that could be affected by a pipeline segment. An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to §195.452(d)(3).) For more information to help in identifying high consequence areas, an operator may refer to:

- (1) Digital Data on populated areas available on U.S. Census Bureau maps.
- (2) Geographic Database on the commercial navigable waterways available on <http://www.bts.gov/gis/ntatlas/networks.html>.
- (3) The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at <http://www.bts.gov/gis/ntatlas/networks.html>.

B. The rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and

mitigate the consequences of a pipeline failure that could affect a high consequence area. (See §§ 195.452 (f) and (i).) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area. The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee. The following list provides guidance to an operator on both the mandatory and additional factors:

- (1) Terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.
- (2) Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.
- (3) Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.
- (4) Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.
- (5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids becomes gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.
- (6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
- (7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.
- (8) The hydraulic gradient of the pipeline.
- (9) The diameter of the pipeline, the potential release volume, and the distance between the isolation points.
- (10) Potential physical pathways between the pipeline and the high consequence area.
- (11) Response capability (time to respond, nature of response).
- (12) Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

II. Risk factors for establishing frequency of assessment.

A. By assigning weights or values to the risk factors, and using the risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed. This list provides some guidance on some of the risk factors to consider (see §195.452 (e)). An operator should also develop factors specific to each pipeline segment it is assessing, including:

- (1) Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.
- (2) Results from previous testing/inspection. (See §195.452(h).)
- (3) Leak History. (See leak history risk table.)
- (4) Known corrosion or condition of pipeline. (See §195.452(g).)
- (5) Cathodic protection history.
- (6) Type and quality of pipe coating (disbonded coating results in corrosion).
- (7) Age of pipe (older pipe shows more corrosion—may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)
- (8) Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment) (see Product transported risk table.)
- (9) Pipe wall thickness (thicker walls give a better safety margin)
- (10) Size of pipe (higher volume release if the pipe ruptures).
- (11) Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement—Alaska); geologic (landslides or subsidence).
- (12) Security of throughput (effects on customers if there is failure requiring shutdown).
- (13) Time since the last internal inspection/pressure testing.
- (14) With respect to previously discovered defects/anomalies, the type, growth rate, and size.
- (15) Operating stress levels in the pipeline.
- (16) Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).
- (17) Physical support of the segment such as by a cable suspension bridge.
- (18) Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

B. Example: This example illustrates a hypothetical model used to establish an integrity assessment schedule for a hypothetical pipeline segment. After we determine the risk factors applicable to the pipeline segment, we then assign values or numbers to each factor, such as, high (5), moderate (3), or low (1). We can determine an overall risk classification (A, B, C) for the segment using the risk tables and a sliding scale (values 5 to 1) for risk factors for which tables are not provided. We would classify a segment as C if it fell above 2/3 of maximum value (highest overall risk value for any one segment when compared with other segments of a pipeline), a segment as B if it fell between 1/3 to 2/3 of maximum value, and the remaining segments as A.

i. For the baseline assessment schedule, we would plan to assess 50% of all pipeline segments covered by the rule, beginning with the highest risk segments, within the first 3½ years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two (2) years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk

segments no later than year five (5).

ii. For our hypothetical pipeline segment, we have chosen the following risk factors and obtained risk factor values from the appropriate table. The values assigned to the risk factors are for illustration only.

Age of pipeline: assume 30 years old (refer to "Age of Pipeline" risk table)–

Risk Value=5

Pressure tested: tested once during construction–

Risk Value=5

Coated: (yes/no)–yes

Coating Condition: Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)–

Risk Value=5

Cathodically Protected: (yes/no)–yes–Risk Value=1

Date cathodic protection installed: five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline's construction is generally considered low risk.)–Risk Value=3

Close interval survey: (yes/no)–no–Risk Value =5

Internal Inspection tool used: (yes/no)–yes. Date of pig run? In last five years–Risk Value=1

Anomalies found: (yes/no)–yes, but do not pose an immediate safety risk or environmental hazard–Risk Value=3

Leak History: yes, one spill in last 10 years. (refer to "Leak History" risk table)–Risk Value=2

Product transported: Diesel fuel. Product low risk. (refer to "Product" risk table)–Risk Value=1

Pipe size: 16 inches. Size presents moderate risk (refer to "Line Size" risk table)–Risk Value=3

iii. Overall risk value for this hypothetical segment of pipe is 34. Assume we have two other pipeline segments for which we conduct similar risk rankings. The second pipeline segment has an overall risk value of 20, and the third segment, 11. For the baseline assessment we would establish a schedule where we assess the first segment (highest risk segment) within two years, the second segment within five years and the third segment within seven years. Similarly, for the continuing integrity assessment, we could establish an assessment schedule where we assess the highest risk segment no later than the second year, the second segment no later than the third year, and the third segment no later than the fifth year.

III. Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

LEAK HISTORY

Safety risk indicator Leak history (Time-dependent defects)1

High > 3 Spills in last 10 years

Low < 3 Spills in last 10 years

1. Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

LINE SIZE OR VOLUME TRANSPORTED

Safety risk indicator Line size

High = 18"

Moderate 10"–16" nominal diameters

Low = 8" nominal diameter

AGE OF PIPELINE

Safety risk indicator Age Pipeline condition dependent¹

High > 25 years

Low 25 years

¹ Depends on pipeline's coating & corrosion condition, and steel quality, toughness, welding.

PRODUCT TRANSPORTED

Safety risk indicator Considerations¹.....Product examples

High (Highly volatile and flammable)(Propane, butane, Natural Gas Liquid (NGL), ammonia).

Highly toxic (Benzene, high Hydrogen Sulfide content crude oils).

Medium Flammable-flashpoint <100F..... (Gasoline, JP4, low flashpoint crude oils).

Low Non-flammable–flashpoint 100+F(Diesel, fuel oil, kerosene, JP5, most crude oils).

¹ The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

IV. Types of internal inspection tools to use.

An operator should consider at least two types of internal inspection tools for the integrity assessment from the following list. The type of tool or tools an operator selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

- (1) Geometry Internal inspection tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;
- (2) Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion.
- (3) Crack Detection Tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

V. Methods to measure performance.

A. General.

(1) This guidance is to help an operator establish measures to evaluate the effectiveness of its integrity management program. The performance measures required will depend on the details of each integrity management program and will be based on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment.

(2) An operator should select a set of measurements to judge how well its program is performing. An operator's objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. A typical integrity management program will be an ongoing program and it may contain many elements. Therefore, several performance measure are likely to be needed to measure the effectiveness of an ongoing program.

B. Performance measures. These measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories:

(1) Selected Activity Measures—Measures that monitor the surveillance and preventive activities the operator has implemented. These measure indicate how well an operator is implementing the various elements of its integrity management program.

(2) Deterioration Measures—Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

(3) Failure Measures—Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

C. Internal vs. External Comparisons. These comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the operator's other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operators' pipeline segments.

(1) Internal—Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area.

(2) External—Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

D. Examples. Some examples of performance measures an operator could use include—

(1) A performance measurement goal to reduce the total volume from unintended releases by -% (percent to be determined by operator) with an ultimate goal of zero.

(2) A performance measurement goal to reduce the total number of unintended releases (based on a threshold of 5 gallons) by ____-% (percent to be determined by operator) with an ultimate goal of zero.

- (3) A performance measurement goal to document the percentage of integrity management activities completed during the calendar year.
- (4) A performance measurement goal to track and evaluate the effectiveness of the operator's community outreach activities.
- (5) A narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to an operator's integrity management program prepared periodically.
- (6) A performance measure based on internal audits of the operator's pipeline system per 49 CFR Part 195.
- (7) A performance measure based on external audits of the operator's pipeline system per 49 CFR Part 195.
- (8) A performance measure based on operational events (for example: relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.
- (9) A performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high risk items.
- (10) A performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

VI. Examples of types of records an operator must maintain.

The rule requires an operator to maintain certain records. (See §195.452(l)). This section provides examples of some records that an operator would have to maintain for inspection to comply with the requirement. This is not an exhaustive list.

- (1) a process for identifying which pipelines could affect a high consequence area and a document identifying all pipeline segments that could affect a high consequence area;
- (2) a plan for baseline assessment of the line pipe that includes each required plan element;
- (3) modifications to the baseline plan and reasons for the modification;
- (4) use of and support for an alternative practice;
- (5) a framework addressing each required element of the integrity management program, updates and changes to the initial framework and eventual program;
- (6) a process for identifying a new high consequence area and incorporating it into the baseline plan, particularly, a process for identifying population changes around a pipeline segment;
- (7) an explanation of methods selected to assess the integrity of line pipe;
- (8) a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data;
- (9) the process and risk factors for determining the baseline assessment interval;
- (10) results of the baseline integrity assessment;
- (11) the process used for continual evaluation, and risk factors used for determining the frequency of evaluation;

- (12) process for integrating and analyzing information about the integrity of a pipeline, information and data used for the information analysis;
- (13) results of the information analyses and periodic evaluations;
- (14) the process and risk factors for establishing continual re-assessment intervals;
- (15) justification to support any variance from the required re-assessment intervals;
- (16) integrity assessment results and anomalies found, process for evaluating and repairing anomalies, criteria for repair actions and actions taken to evaluate and repair the anomalies;
- (17) other remedial actions planned or taken;
- (18) schedule for evaluation and repair of anomalies, justification to support deviation from required repair times;
- (19) risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;
- (20) criteria for determining EFRD installation;
- (21) criteria for evaluating and modifying leak detection capability;
- (22) methods used to measure the program's effectiveness.

VII. Conditions that may impair a pipeline's integrity.

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. The following are some examples of conditions that an operator should schedule for evaluation and remediation.

- A. Any change since the previous assessment.
- B. Mechanical damage that is located on the top side of the pipe.
- C. An anomaly abrupt in nature.
- D. An anomaly longitudinal in orientation.
- E. An anomaly over a large area.
- F. An anomaly located in or near a casing, a crossing of another pipeline, or an area with suspect cathodic protection.

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